BOSTON EDISON COMPANY

Direct Testimony of Bryant K. Robinson

Exhibit BEC-BKR

D.T.E. 00-82

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Bryant K. Robinson. My business address is 800 Boylston Street, Boston, Massachusetts 02199.

Q. By whom are you employed and in what capacity?

A. I am Manager of Revenue Requirements for the regulated operating companies of NSTAR. In this capacity, I am responsible for all regulatory filings concerning the financial requirements of Boston Edison Company ("Boston Edison" or the "Company"), Cambridge Electric Light Company, Commonwealth Electric Company and Commonwealth Gas Company.

Q. Please briefly summarize your educational background and business experience.

A. I graduated from the University of Massachusetts – Dartmouth in 1978 earning a Bachelor's degree in Finance and from Northeastern University in 1988 with a Master's in Business Administration. For the years 1978 to 1983, I worked in the banking industry with State Street Bank and Trust Company and Boston Safe Deposit and Trust Company. In 1983, I joined Boston Edison's Audit Department, and held Staff Auditor and Senior Auditor positions. In 1989, I joined the Revenue Requirements Department as a Financial Research Analyst.

Subsequently, I have held positions as Senior Financial Research Analyst, Senior Financial Consultant and Principal Financial Analyst.

Q. Please describe your present responsibilities.

A. As Manager of Revenue Requirements, I am responsible for directing the preparation of financial data required for rate case filings and serve as the revenue requirements witness. My responsibilities currently include, among a variety of other financial services, the reconciliation of the Company's Transition Charge that forms the basis of my testimony today.

Q. Have you previously testified before the Department of Telecommunications and Energy (the "Department") or any other regulatory body?

A. Yes, I testified in the Company's prior Transition Charge true-up proceedings, D.T.E. 98-111 and D.T.E. 99-107. In addition, I presented cost of service testimony regarding the wholesale fuel adjustment clause to the Federal Energy Regulatory Commission ("FERC").

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Section 1A(a) of Chapter 164 of the Acts of 1997 (the "Act") requires the Department to review and to reconcile the difference between projected transition costs and actual transition costs periodically. The Company's Restructuring Settlement, as approved in D.P.U./D.T.E. 96-23, requires an annual reconciliation to coincide with the implementation of new rates (Restructuring Settlement, §

V.E.). My testimony provides a description of the methodology used by the Company to reconcile the forecast of Transition Charge revenues for the period January 1, 1999 through December 31, 1999, which relies on previously filed information contained in the Company's filing in D.T.E. 99-107, with actual information for the same period. This includes a final update of transaction costs and other costs associated with the sale of Pilgrim Station. In addition, this reconciliation provides updated information concerning Transition Charge revenues and transition costs for 2000 utilizing actual data where available along with forecast data for the remainder of the year. Finally, this filing includes the Company's proposal to revise and fine-tune the manner in which Transition Charge revenues are determined and reconciled with transition costs. The results of this reconciliation are reflected in Exhibit BEC-BKR-1 and associated supporting Exhibits BEC-BKR-2 through BEC-BKR-4.

The Company anticipates making a supplementary filing in the Spring of 2001, once the accounting for the year 2000 has been completed and actual amounts are known. At that time, actual 2000 information will be available to reconcile both 1999 and 2000 transition charges as part of this proceeding. Subsequent transition charge reconciliations would occur in the same manner. As a result, the Company's next reconciliation filing in the Fall of 2001 would reconcile 2001 transition costs, based on preliminary data filed in the Fall of 2001 and updated with actual data in 2002.

Finally, my testimony provides a reconciliation of retail transmission costs and revenues and calculates the proposed 2001 average retail transmission rate.

Q. Please describe the primary exhibits included as attachments to your testimony.

A. I have included five exhibits that are used: (i) to develop the Company's reconciliation of Transition Charge revenues and transition costs for the period January 1, 1999 through December 31, 1999; (ii) to calculate the Company's proposed Transition Charge for calendar year 2001; and (iii) to develop the 2001 average retail transmission rate. These five exhibits are described as follows:

Exhibit BEC-BKR-1

An eight-page exhibit that summarizes the development of Boston Edison's proposed Transition Charge for 2001 and the development of the Company's reconciliation of Transition Charge revenues for the period January 1, 1999 through December 31, 1999. This schedule incorporates the proposed method of computing and reconciling revenues collected from the Transition Charge.

Exhibit BEC-BKR-2

A thirteen-page exhibit that summarizes the revenue credits and damages, costs, or net recoveries from claims. The effect of these adjustments is reflected in Exhibit BEC-BKR-1, page 4, Column O. These adjustments include Pilgrim Residual Value Credit updates, fossil residual value credit adjustments, a generating unit performance adjustment, final fuel charge reconciliation adjustments and a distribution revenue loss adjustment resulting from rate-design constraints.

Exhibit BEC-BKR-3

A one-page exhibit reflecting the Company's nuclear employee severance and retraining payments for 1999 based on final information, as reflected in Exh. BEC-BKR-1, Page 4, Column N.

Exhibit BEC-BKR-4

A calculation supporting the Company's 1999 reconciliation adjustment associated with the Pilgrim PBR formula, as reflected in Exh. BEC-BKR-1, page 4, Column P.

Exhibit BEC-BKR-5

The development of the 2001 average retail transmission rate.

III. BACKGROUND OF BOSTON EDISON'S TRANSITION CHARGE

Q. What is the purpose of Boston Edison's Transition Charge?

A. As approved by the Department as part of Boston Edison's Restructuring Settlement, and as set forth in the Act, the Transition Charge recovers the above-market costs of generation-related investments and obligations that electric companies have undertaken to provide service to their customers under traditional utility regulation. The Act authorizes and directs the Department to allow any approved transition costs to be recovered from customers through a non-bypassable Transition Charge collected by the distribution company providing service to such customers. G.L. c. 164, § 1G(e). The Company's Restructuring Settlement, as approved by the Department in D.P.U./D.T.E. 96-23, provides for the implementation of a Transition Charge to be applied on a uniform cents per kilowatthour ("kWh") basis.

Q. What is the history of Boston Edison's Transition Charge?

A. Boston Edison's Transition Charge first became effective on March 1, 1998 at an initial level of $0.03510 per kWh. As a result of the Department-approved divestiture of Boston Edison's non-nuclear generating units on May 15, 1998**,** Boston Edison's Transition Charge was reduced by approximately 14 percent, to an average level of $0.03030 per kWh, effective June 1, 1998. Boston Edison Company, D.T.E. 97-113 (1998). On November 4, 1998, Boston Edison filed the first annual reconciliation of its Transition Charge along with proposed revised tariffs for 1999 (the "First Reconciliation"). On December 31, 1998, the Department allowed the Company's proposed tariffs to take effect, subject to future reconciliation. As a result, the Company's Transition Charge was again lowered to an average level of $0.02760 per kWh. On October 19, 1999, the Department issued its Order in D.T.E. 98-111, ruling on various elements of the Company's First Reconciliation. Boston Edison Company, D.T.E. 98-111 (1999). The Company filed a motion for reconsideration, which was resolved by the Department's approval of a settlement concerning the accounting for above-market purchased-power contracts that are used to provide power for Standard Offer and Default Service. Boston Edison Company, D.T.E. 98-111-A (2000).

On July 30, 1999, the Company filed revised tariffs with the Department implementing a reduction to the Company's Transition Charge. That adjustment reflected, on a preliminary basis, the Company's divestiture of Pilgrim Station and the issuance of rate reduction bonds to securitize the fixed component of the Company's Transition Charge. It also implemented the Act's requirement for a 15 percent rate reduction for all of the Company's retail customers. These tariffs were amended on August 25, 1999 and August 31, 1999 in response to the Department's August 19, 1999 letter ordering all rate classes and all billing determinants within rate classes to reflect a 15 percent rate reduction. New rates became effective on September 1, 1999 which reflected the lowering of the transition charge to an average level of $0.02546 per kWh. In order to achieve the required overall rate reduction in accordance with the Department's rate design directives, it was also necessary to defer a portion of the Company's distribution revenues, for which the Company indicated that it would seek future recovery through the Transition Charge.

On November 30, 1999, the Company filed the second annual reconciliation of its Transition Charge along with proposed tariffs for 2000, which filing was docketed as D.T.E. 99-107 (the "Second Reconciliation"). On January 5, 2000, the Department approved the Company's proposed tariffs for 2000, subject to future reconciliation. As a result, the Transition Charge was further reduced to an average level of $0.01891 per kWh. The Second Reconciliation included a final true-up of Transition Charge revenues and transition costs for 1998 and also updated the results of the Pilgrim divestiture and the securitzation of the fixed component of the Transition Charge. All issues in the Second Reconciliation, except one, were resolved by settlement, which was approved by the Department on August 31, 2000. Boston Edison Company, D.T.E. 99-107-A (2000). The one unresolved issue was briefed by the parties and remains pending before the Department as of November 1, 2000.

This filing represents the third reconciliation of the Company's Transition Charge, filed in accordance with the Restructuring Settlement as approved by the Department in D.P.U./D.T.E. 96-23.

Q. What is Boston Edison's proposed Transition Charge for the year 2001?

A. As shown in Exhibit BEC-BKR-1, page 1, Column C, the Company's proposed 2001 Transition Charge is $0.01397 per kWh, to become effective on January 1, 2001. This represents a reduction of $0.00494 per kWh from the Company's current level of Transition Charge.

Q. Please explain any major differences between the methodology used to compute the Company's proposed Transition Charge for 2001 and the methodology that has been employed in prior years' filings.

A. The basic methodology continues to follow very closely the applicable provisions of the Restructuring Settlement and the methodology employed in last year's true-up filing. Three areas in which there have been changes that I will highlight are: (i) the manner of reconciling Transition Charge revenues; (ii) the use of updated projections of kWh sales and transfer prices for purchased power contracts that are used to supply Standard Offer Service; and (iii) the manner of setting the Transition Charge for 2001 (and for future years) to avoid excessive over-collection or under-collection of revenues.

The change in the manner of reconciling Transition Charge revenues was discussed during last year's true-up proceeding and may be briefly described as a manner of reconciling based on actual revenues received for kWh delivered, rather than on the basis of kWh delivered times an average rate. In the Company's prior filing, Transition Charge revenues were reconciled by, in effect, assuming that every kWh delivered collected the "average" per-kWh Transition Charge established by the Department. The revenue reconciliation therefore represented a reconciliation solely of sales volumes, because it calculated the Transition Charge revenue reconciliation by accounting for the difference between the estimated kWh delivered and actual kWh delivered multiplied by the average Transition Charge for the year. Although, with the exception of Rate WR, every rate is designed to collect the "average" approved Transition Charge, the rate design, for some customer classes, collects the Transition Charge through peak and off-peak rates and demand charges. Mr. LaMontagne has designed the rates to collect the average Transition Charge for each class, but in practice this produces the precisely correct level of revenues only if the load patterns are exactly the same as those that serve the basis of the rate-design models. Deviations in load patterns within and between customer classes means that the actual Transition Charge revenues are likely to diverge from the amount the rates are designed to collect each year. This change to the manner of reconciling revenues leads to a more accurate true-up of revenues for the Company and its customers.

Q. Please describe the Company's use of updated projections to its forecast of GWh sales.

A. The use of updated projections is largely a matter of replacing certain outdated forecasts or assumptions contained in the original Restructuring Settlement with more accurate or updated information. Since all such projections are eventually reconciled to actual, the major advantage for 2001 and future years is a more timely matching of costs and revenues. Under the methodology used in previous years, projections of kWh sales, and, therefore, revenues were understated, resulting in over-collections, which were later returned to customers through a multi-year amortization (with appropriate carrying charges). Similar over-collections would result from the use of extremely low market price projections for purchase power contracts which were, in fact, being used to supply Standard Offer Service and, therefore, are more correctly priced at the transfer price determined in accordance with the Reconciliation Settlement with DOER that was approved by the Department in D.T.E. 98-111-A.

Q. Please explain the Company's proposal to return all existing Transition Charge over-collections in the 2001 Transition Charge.

The final change I have mentioned relates to the timing of the proposed return of over-collections. The prior methodology, which amortized the over/under collection and related return over three years, resulted in a larger-than-necessary

Transition Charge. We believe that the proposed methodology will result in a more precise reconciliation, but will also result in a Transition Charge that more closely tracks the annual transition costs that are to be recovered. In addition, the Company's proposal to calculate the 2001 Transition Charge based on the return to customers of all existing over-collections in transition costs that have accumulated to date is reasonable, appropriate and serves the interests of all customers because it reduces the proposed Transition Charge below the level otherwise calculated under the Company's earlier methodology and creates extra "headroom" that can be used to reduce outstanding deferrals for Default Service and Standard Offer Service. There is no reasonable basis to limit the refund of prior-period over-collections when calculating the proposed Transition Charge for the coming year.

IV. CALCULATION OF THE PROPOSED TRANSITION CHARGE

Q. Please describe the categories of transition costs.

A. Boston Edison's transition costs, as set forth in the Settlement Agreement, consist primarily of two components: (1) a Fixed Component that includes the unrecovered net book value of the Company's generation plant and generation-related regulatory assets, net of the proceeds from the divestiture of Boston Edison's generating facilities, as specified in the Act; and (2) a Variable Component that includes Boston Edison's nuclear decommissioning costs, above-market purchased-power contract payments, above-market fuel transportation contracts, payments in lieu of taxes, employee severance and retirement costs, and above-market nuclear generation costs. I say "primarily" because there also a few other elements of cost, such as those related to the deferral of the Retail Access Date[1] and the Transition Charge Mitigation Incentive that are recovered through the Transition Charge, but which are not clearly assigned to either the Fixed or the Variable Component—these have been labeled as "Other" in the exhibits accompanying my testimony. The Fixed Component, as presented beginning in last year's filing and continuing in this and future filings, reflects the schedule of Amortization and Interest and Expense for the proceeds received on July 28, 1999 for the five series of Rate Reduction Bonds that were issued to refinance the Fixed Component as it is described in (1) above. All adjustments to the Fixed Component are adjusted through the Company's Variable Component.

Q. How did Boston Edison develop its proposed Transition Charge to become effective on January 1, 2001?

A. The Transition Charge is developed in Exhibits BEC-BKR-1 through BEC-BKR-4. These exhibits include updated amounts for both the Fixed and Variable components of the Transition Charge that reflect the most current information available to the Company. As shown in Exhibit BEC-BKR-1, page 1, the

[1] As described below, the Company's Restructuring Settlement anticipated a retail access date of January 1, 1998, rather than the actual retail access date of March 1, 1998. The Restructuring Settlement, Attachment 3, § 2.9(b), establishes a methodology for this timing difference. Pursuant to the Restructuring Settlement, the monthly adjustment is accumulated in the Reconciliation Account and is reflected in the adjustments to the Transition Charge starting January 1, 2001.

required 2001 revenues are divided by the forecast of 2001 kWh retail deliveries to arrive at the Transition or Access Charge rate shown in column C.

<u>EXHIBIT BEC-BKR-1</u>

Q. Please describe Exhibit BEC-BKR-1.

A. Exhibit BEC-BKR-1 represents the update to the Transition Charge and is made up of the following eight pages:

<u>Page</u>	<u>Description</u>
1.	Transition Charge Calculation for 2001
2.	1999 Transition Revenues
3.	Securitized Fixed Component
4.	Variable Component
5.	Other Variable Costs
6.	Transition Charge Mitigation Incentive Mechanism
7.	Power Contract Obligations (GWh)
8.	Power Contract Obligations (Millions of Dollars)

Q. Please explain page 1, the Transition Charge Calculation for 2001.

A. Page 1 is a summary page that compares billed Transition Charge revenues to actual transition costs to arrive at the annual over- or under-collection for each year. This page contains a mixture of historical information reflecting the outcome of last year’s true-up proceeding for 1998, data for 1999 that are being reconciled in this proceeding, preliminary, part actual/part forecast data for 2000, and projected data for 2001 and thereafter. Column B shows the actual and forecast gigawatt-hours (“GWh”) delivered (both billed and unbilled) for each calendar year. The data for 1999 are actual data, and the 2000 data are actual sales for nine months and three months of forecasted sales. The forecast for 2001 reflects the Company's current internal projection of sales. Subsequent years utilize the 2001 sales forecast, increased by 2 percent per year.

For 1999, Column C is the average Transition Charge billed, calculated by dividing Column D by Column B. For 2000 Column C is the D.T.E. 99-107 average Transition Charge rate of $0.01891 per kWh approved by the Department on January 5, 2000. For the year 2001 and after, Column C is calculated by dividing Column J (total expenses) by Column B (GWh delivered). The Transition Charge revenues for delivered GWh (Column D) shows the actual Transition Charge revenues for 1999, as calculated on page 2, and projected revenues for 2000. For later years, Column D is the same as Column J, reflecting the Company's intention that the Transition Charge be set at the level such that projected revenues match projected expenses. Transition Charge expenses, or transition costs, are shown in Columns E through J. The total Fixed Component (Column E) is shown on page 3. The total Variable Component (Column F) is calculated on page 4 (Column Q). The Other Component (Column G), reflects certain other transition costs, as shown on pages 5 and 6. To these current-year expenses, an adjustment is made for the prior year over- or under-collection (Column H), including interest (Column I), using the Restructuring Settlement's carrying charge of 10.88 percent.

The amounts shown on page 1, Columns E through I, are summed, representing the total actual Transition Charge expense, as shown in Column J, to be collected in the current year. Column K compares the revenues in Column D to the expenses in Column J to arrive at the balance of over- or under-collections for the current year. References for each of the columns can be found at the foot of the page. This page provides a summary comparison of annual Transition Charge revenues and transition costs.

The 1998 Transition Charge reconciliation amount shown in Column K is the amount set forth in the August 4 Settlement filed with and approved by the Department in D.T.E. 99-107 (see August 4 Settlement, § 2.5). With this filing for 1999 and thereafter, the Company proposes to refine the calculation of its Transition Charge over- or under-collection by reconciling the forecasted Transition Charge revenues with the actual revenues associated with delivered GWh in the same year. This calculation of 1999 Transition Charge revenues is shown on page 2.

Q. Please explain page 2, 1999 Billed and Unbilled Transition Revenues.

A. The billed revenues are taken from the Company's general ledger. The commercial Transition Charge revenues include the WR rate and the Company's Special Contracts. In order to match billed revenues for 1999 with the revenues associated with kWh delivered during 1999, it is necessary to adjust for unbilled revenues for the end of 1998 with a similar, but opposite, adjustment for the end of 1999. The unbilled revenues for the end of 1998 are estimated using the unbilled kWh and the average transition rate for December 1998. These unbilled revenues are deducted from the 1999 billed revenues, and the 1999 unbilled revenues are added to the 1999 billed revenues in order to calculate an appropriate adjustment for 1999 Transition Charge unbilled revenues for kWh delivered in 1999. The unbilled revenue balance for 1999 is calculated in the same way as the unbilled revenue balance for 1998 was calculated. The kWh delivered in 1999 are the billed kWh less the unbilled kWh at the start of 1999 (which were delivered in 1998) plus the unbilled kWh at the end of 1999 which were delivered but unbilled in 1999.

Q. Please describe Page 3, Securitized Fixed Component.

A. Page 3 of Exhibit BEC-BKR-1 shows the balance of Fixed Component obligations resulting from securitization beginning on July 29, 1999. The total annual Fixed Component reflects the amortization of principal (Column C), the associated interest from the bonds and the administration expense associated with the securitization transaction (Column D). The amounts shown for 1999 and later years are reflected in Exhibit BEC-BKR-1, page 1, Column E. The Company proposed in D.T.E. 99-107 that any future changes to the securitization balances be credited or debited to the Variable Component (included in Exhibit BEC-BKR-1, page 4, Column O). Updated amounts for the Pilgrim divestiture are shown in Exhibit BEC-BKR-2.

Q. Please explain page 4, Variable Component.

A. Page 4 of Exhibit BEC-BKR-1 provides a summary of the Company's variable cost adjustments. The calculation is used on page 1 to develop the Variable Component of the Company's proposed Transition Charge. The payments in Column H(a) represent the $23 million annual Nuclear Costs Independent of Operation ("NCIO") (which is being flowed through to the new owner of Pilgrim, Entergy Nuclear Generation Company ("Entergy")) through the end of 2000, as outlined in the Restructuring Settlement, page 234.[2] The Actual Nuclear Decommissioning (Column H(b)) reflects decommissioning costs incurred of $11.020 million in 1998 and $7.257 million in 1999. The 1998 cost is the amount filed in D.T.E. 98-111 and approved in the Department's order dated October 19, 1999 (page 28). The 1999 cost is the per book amount for the period January 1, 1999 through July 13, 1999, the date of sale of Pilgrim.

Q. Please explain power-purchase obligations and market value on page 4 (Columns I & J).

A. Columns I and J calculate the amount by which the Company's actual power contract obligations exceed the actual revenues received by the Company for these contracts (Column I minus Column J). This amount represents the continued amount of strandable cost associated with the Company's power

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[2] Restructuring Settlement, page 234, Section 2.1(a)"If Pilgrim is sold, the revenues covering fixed operating costs included in this section will continue to be received but will be flowed through to the purchaser."

contract obligations. The Company's 1999 actual cost paid for this power is shown in Column I. The Total Power Obligations are detailed in Exhibit BEC-BKR-1, page 8. Since all of this power (see the 1999 Annual Purchase Power GWh obligations, which are detailed in Exhibit BEC-BKR-1, page 7) was effectively used to supply Standard Offer Service, the Company determined a "transfer price" to account for the market cost of this power.

Q. Please explain the use of a transfer price.

A. The transfer price is used to establish the amount of power contract obligations that are collected through the Transition Charge. In 1999 and 2000, the Company used the Standard Offer Service retail rate of $0.031and $0.034 per kWh, respectively (net of line losses) as the transfer price in calculating Column J. Please note that this treatment is consistent with the Department's approval of the settlement agreement with DOER filed on November 30, 1999, and approved in the Department's order in D.T.E. 98-111-A. The forecast of power contract market value for December 2000 includes an additional $0.00581 per kWh to reflect the Standard Offer Fuel Adjustment pending before the Department in D.T.E. 00-70. In 2001, an additional $0.013 per kWh is added to the Standard Offer Service rate to reflect the Company's estimate of the average 2001 Standard Offer Service Fuel Adjustment. This adjustment is applied only to those Power Purchase Agreements("PPAs") that have a fuel adjustment component. All of the Company's PPAs except for Entergy and NEA 1 fall into this category. For the years 2002 through 2004, the transfer price is based on the Company's Standard Offer Service pricing, without any assumed Fuel Adjustment. After 2004, the transfer price is based on the values originally provided in the Restructuring Settlement and has not been updated. These transfer prices are consistent with those utilized in the exhibits showing the cost of Standard Offer Service supply in the testimony of Rose Ann Pelletier in this filing.

Q. Please describe page 4, Column K, Actual Purchased Power Contract Buyouts.

A. Column K, Actual Purchased Power Contract Buyouts, reflects that there are no contract buyouts for 1999 reflected in the Variable Component. As the Department is aware from its Order in D.T.E. 99-16, the Company bought out of the L'Energia contract in 1999, but instead of including the cost as a variable cost it included the cost in the amount securitized, as approved in D.T.E. 99-118. Other than the L'Energia buyout, the Company has not entered into any power contract buyouts during the period 1998 through December 31, 1999.

Q. Please explain page 4, Column L, Actual Above Market Fuel Transportation Costs.

A. The Company's above-market fuel transportation costs for 1999 and thereafter are $0 because the Company divested its fossil generating facilities in 1998.

Q. Please explain page 4, Column M, Actual Payments in Lieu of Property Taxes.

A. The payments in Column M represent the Company's unreimbursed obligation to the Town of Plymouth for property taxes, or "in lieu of taxes", associated with Pilgrim Station following the July, 1999 sale to Entergy Nuclear Generation Company. The Company's obligation to the Town of Plymouth results from an agreement that was mandated under Section 71 of the Electric Restructuring Act and which was approved by the Department in D.T.E. 98-53. Prior to the sale of Pilgrim, property tax payments were accounted for through the Performance Based Rate for Pilgrim. Under the purchase and sale agreement with Entergy, a substantial portion of the required payments to Plymouth for 1999 and 2000 have been or will be reimbursed by Entergy. Actual net, unreimbursed payments made in 1999 and 2000 are reflected in Column M. The amounts for 2001 and future years reflect the maximum tax settlement amounts to Plymouth, but do not include an estimate of offsetting payments, if any, that may be made by Entergy which would serve to reduce these amounts. Please note that Column O reflects the reimbursement by Pilgrim contract customers of their share of required payments to Plymouth.

Q. Please describe page 4, Column N, Actual Employee Severance and Retraining Costs.

A. These costs represent severance and retraining costs of employees who were affected by the divestiture of the Company's generation facilities. The 1998 cost (credit) in this category is associated with the sale of the Company's fossil units in 1998 and was specifically approved in D.T.E. 98-111. The 1999 costs associated with the sale of the Pilgrim nuclear unit are included for approval in this filing. Details of these costs are shown in Exhibit BEC-BKR-3.

Q. Please explain page 4, Column O, Actual Revenue Credits and Damages, Costs, or Net Recoveries from Claims.

A. Column O reflects actual revenue credits and/or costs associated with any outstanding claims by or against the Company as shown in Exhibit BEC-BKR-2. The amount shown for 1998 reflects the approved transition adjustment for the MWRA that was the subject of the August 4, 2000 settlement agreement that was filed in D.T.E. 99-107. See D.T.E. 99-107, Settlement Exhibit BEC-4, page 1, line 20. For 1999, as set forth in more detail in Exhibit BEC-BKR-2, the adjustments consist of: (1) Pilgrim Residual Value Credits; (2) Fossil Residual Value Credit Adjustments; (3) Generating Unit Performance Program Adjustments; (4) Final Fuel Adjustment Reconciliation; and (5) Distribution Revenue Losses Resulting From Rate Design Constraints. Because the Company's proposed revenue reconciliation methodology in this filing reconciles the Transition Charge based on revenues for delivered GWh (reflected on Exhibit BEC-BKR-1, page 1), the Company has eliminated the requirement for a separate MWRA Transition Charge adjustment in 1999 and all future years.

Q. Please explain page 4, Column P, Actual Performance Based Rates ("PBR") for Nuclear Units remaining after Market Valuation.

A. The updated 1999 Pilgrim PBR calculations, as shown in Column P, are detailed in Exhibit BEC-BKR-4, which is discussed more fully later in my testimony. The methodology used to calculate the amount shown in Column P is based on the Restructuring Settlement, Attachment 3, Section 2.7.

Q. Please explain page 4, Column Q, the Actual Total Variable Component.

A. Column Q is calculated by summing each of the components I have discussed previously which are contained in Column H(a), Column H(b), Column I minus Column J, Column K, Column L, Column M, Column N, Column O and Column P. These amounts are carried forward to page 1, Column F.

Q. Please explain page 5, Other Variable Costs.

A. The other variable costs shown on page 5 reflect additional variable costs to be included in the Company's reconciliation account. The adjustment for Deferral of the Access Charge Date, as reflected in Column B, accounts for the fact that the Company's Restructuring Settlement assumed a retail access date of January 1, 1998 rather than the actual retail access date of March 1, 1998. Pursuant to Section 2.9(b) of Attachment 3 to the Restructuring Settlement, the monthly adjustment associated with deferral of the retail access date is accumulated in the Reconciliation Account to be reflected in the adjustments to the Transition Charge starting January 1, 2001. The $0.901 million adjustment for actual generation related transmission in 1998 carries forward the amount filed in D.T.E. 99-107, Exhibit BEC-5. The Transition Charge Mitigation Incentive, as shown in Column D, reflects the incentive established in the Restructuring Settlement (Section 2.9(d) of Attachment 3) which allows the Company to earn additional revenues based on its reduction of the Transition Charge rate. The amount of the incentive is derived in Exhibit BEC-BKR-1, page 6, as discussed below.

Q. Please explain Exhibit BEC-BKR-1, page 6, Transition Charge Mitigation Incentive Mechanism.

A. Pursuant to the Restructuring Settlement, recovery of the Company's Transition Charge Mitigation Incentive begins in 2001. From January 1, 2001 through December 31, 2009, the Transition Charge Mitigation Incentive increases the Variable Component reflecting the Company's mitigation of the Transition Charge by reducing the cumulative average Transition Charge below the 1998 level of $0.03510 per kWh. Exhibit BEC-BKR-1, page 6, details the schedule of incentives for each level of the cumulative average Transition Charge in each year from 2001 through 2009.

Q. Please explain Exhibit BEC-BKR-1, page 7, Annual Power Contract Obligations in GWh.

A. Exhibit BEC-BKR-1, page 7, reflects the Company's actual GWh power purchase obligations for 1998 and 1999. For 2000, the data include eight months actual and four months forecast. For 2001, the data include an updated Company forecast, and the years 2002 and beyond are as forecast in D.T.E. 99-107.

Column L reflects the Company's sale of Pilgrim, which resulted in a Department-approved PPA with Entergy terminating in 2006. See Boston Edison Company, D.T.E. 98-119 (1999). Column H reflects the termination of the L'Energia power purchase obligation that was approved by the Department in D.T.E. 99-16.

Q. Please explain Exhibit BEC-BKR-1, page 8, Annual Power Contract Obligations in Million of Dollars.

A. Exhibit BEC-BKR-1, page 8 reflects the actual cost of the Company's power purchase obligations for 1998 and 1999 including both energy and capacity costs. As described in Exhibit BEC-BKR-1, page 7, the power contract obligation is reduced by the L'Energia buyout, and increased by the addition of Pilgrim as a purchase-power obligation in 1999. As with page 7, the data for 2000 are eight months actual and four months forecast. For 2001, the data include an updated Company forecast and the years 2002 and beyond are as forecast in D.T.E. 99-107, with the exception of Connecticut Yankee which has been changed to reflect the permanent shutdown of that unit.

Exhibit BEC-BKR-2

Q. Please describe Exhibit BEC-BKR-2.

A. Exhibit BEC-BKR-2 serves a similar function as Exhibit BEC-4 in last year's filing in D.T.E. 99-107. It accumulates a number of adjustments to the Variable Component of the Transition Charge, which are reflected together in Exhibit

BEC-BKR-1, page 4, Column O, Revenue Credits & Damages, Costs or Net Recoveries from Claims. These include adjustments to the residual value credits associated with the Company's generation divestitures, adjustments associated with the final accounting for the Company's Generating Unit Performance Program and Fuel Charge dockets, adjustments associated with distribution revenue losses incurred due to restructuring-mandated rate design constraints, and certain miscellaneous additional credits or costs. This exhibit also reflects the effect of the August 4, 2000 settlement in D.T.E. 99-107.

Q. Please explain the adjustments related to the Pilgrim Residual Value Credit ("PRVC") shown on Exhibit BEC-BKR-2, page 1.

A. In D.T.E. 98-119 (1999), the Department approved the Company's proposed sale of Pilgrim to Entergy. The transaction was completed on July 13, 1999. The Company's most recent estimate of the PRVC attributable to the transaction, including final costs with respect to RFO #12, was approved by the Department in D.T.E. 99-107-A and is reflected in the column labeled "D.T.E. 99-107 Settlement". Three additional changes, or updates, are reflected in this filing. As shown on page 1, line 10, the total of these three adjustments results in a change of ($24.959) million. The adjustments reflect the following: (1) a $0.120 million increase in the actual 1999 transaction costs associated with the divestiture of Pilgrim; (2) a credit for higher net proceeds from the Company's issuance of rate reduction bonds of $0.081 million from previously forecasted amounts at the time of the settlement in D.T.E. 99-107; and (3) a $24.998 million increase in the PRVC associated with the buy-out settlement reached with the 14 municipal electric companies (the "Municipals") who formerly held Unit Contracts for power from Pilgrim.[3] As part of the Department's approval of the Company's Pilgrim divestiture, the Company agreed to "revenue credit" all such amounts received from the Municipals. Boston Edison Company, D.T.E. 98-119 (1999). In the D.T.E. 99-107 filing, the Municipals revenue credits for 1999 were estimated as $1.433 million (see Settlement Exhibit BEC-4, page 1 of 12, line 9). As of December 31, 1999, the Company received $24.125 million from the Municipals as a final buy-out settlement of all contractual obligations. In addition, during 1999 the Company netted $2.306 million from the Municipals relating to the difference in billing under the approved Entergy buyback contracts and the Company's post-sale billings to the Municipals under their pre-existing Unit Contracts. Accordingly, the total PRVC adjustment on account of the Municipals, as shown in Exhibit BEC-BKR-2, page 1, line 9, is $24.998 million ($24.125 million plus $2.306 million minus $1.433 million).

[3] The following 14 Municipals were a part of the settlement: City of Holyoke Gas and Electric Department, City of Westfield Gas and Electric Light Department, Littleton Electric Light Department, Marblehead Municipal Light Department, Middleborough Gas and Electric Department, North Attleboro Electric Department, Peabody Municipal Light Plant, Reading Municipal Light Department, Shrewsbury Electric Light Plant, Templeton Municipal Light Plant, Town of Boylston Municipal Light Department, Town of Hudson Light and Power Department, Town of Wakefield Municipal Light Department and West Boylston Municipal Lighting Plant.

Exhibit BEC-BKR-2, pages 2 through 8 provide additional detailed update of the post-settlement Pilgrim Residual Value Credit calculation, including each of the adjustments mentioned previously. Please note that page 8 provides the updated Pilgrim transaction costs while page 7 reflects the Pilgrim RFO #12 settlement.

Q. Please explain the adjustments associated with the Residual Value Credit ("RVC") for the Company's fossil units.

A. The RVC Adjustments shown in Exhibit BEC-BKR-2, page 1, lines 12 through 16, reflect the Company's Fossil Residual Value Credit adjustments for 1999. These adjustments, together with applicable interest, are included in the Company's 1999 Variable Component reconciliation account, as shown on Exhibit BEC-BKR-2, line 13 through line 15. These adjustments were previously set forth in D.T.E. 99-107, Exhibit BEC-3 and have not changed.

Q. Please explain the adjustments associated with the Company's Generating Unit Performance Program.

A. The Generating Unit Performance Program Adjustment shown in Exhibit BEC-BKR-2, page 1, line 19, reflects the amount of a Company refund to its retail customers as a result of a settlement of the Company's pre-restructuring generating unit performance proceedings. The amount of the refund was $2.5 million which was agreed to be returned as a credit to the Company's Transition Charge. See Boston Edison Company, D.P.U. 95-1A-1/96-1A-1/97-1A-1/98-1A-1 (August 1, 2000).

Q. Please explain the adjustment for the final Fuel Charge reconciliation.

A. Pursuant to the Department's order in D.T.E. 98-13-A, the Company was directed to refund the remaining balance in its fuel charge reconciliation account as of March 1, 1998 by means of a direct per-kWh credit to customers over a six-month period. The Company complied with this directive, however because of differences between forecast and actual kWh sales the Company over-refunded approximately $777,000. The Company had proposed to the Department that any final remaining credit or debit be reflected in the Company's Transition Charge account.

Q. Please describe the distribution revenue loss because of rate-design constraints that is shown in Exhibit BEC-BKR-2, page 1.

A. Lost base distribution revenues were incurred by the Company in response to Department rate-design mandates associated with the implementation of the 15 percent rate reduction for all customers as of September 1, 1999 as required by the Act. In performing the required adjustments to distribution rates, it was not possible to develop new rates that were consistent with the Department's rate-design mandates on a revenue-neutral basis. As a result the Company experienced an annualized base distribution revenue reduction of approximately $2.054 million in 1999, or approximately $0.685 million for the period September 1, 1999 through December 31, 1999. A similar result occurred in designing rates for 2000 with a distribution loss of approximately $0.219 million attributable to

2000. Calculations underlying these amounts are shown in Exhibit BEC-BKR-2, page 11.

Q. Please describe the Pilgrim contract customer credits shown in Exhibit BEC-BKR-2, page 1.

A. These credits reflect the Pilgrim contract customers' 22 percent share of NCIO and unreimbursed (by Entergy) payments in lieu of taxes to Plymouth for 1999 and 2000. The payment by Pilgrim contract customers of their share of NCIO payments flowed through to Entergy was negotiated as a part of the Pilgrim divestiture transaction and will cease after 2000 when NCIO payments end. The calculation is shown in Exhibit BEC-BKR-2, page 12. The calculation of the contract customer payment responsibility for payments in lieu of taxes is shown on Exhibit BEC-BKR-2, page 13. Such payments are anticipated to continue through 2012 and are reflected in Exhibit BEC-BKR-1, page 4, column O.

Q. Please explain pages 9 and 10 of Exhibit BEC-BKR-2.

A. These are unchanged from the Company's filing in D.T.E. 99-107. Page 9 provides detail concerning the Company's termination costs associated with the buyout of the L'Energia PPA. These costs were securitized in 1999, in accordance with the Department's order in D.T.E. 99-118. Page 10 provides a breakdown of the transaction costs associated with the L'Energia buyout that was filed in D.T.E. 99-107 Exhibit BEC-4, pages 9 and 10 of 12.

<u>Exhibit BEC-BKR-3</u>

Q. Please explain Exhibit BEC-BKR-3.

A. The costs shown in Exhibit BEC-BKR-3 represent actual costs of employees whose employment with the Company terminated as a result of the divestiture of the Company's Pilgrim facility in 1999. The total amount, which represents severance and retraining costs, is $25.081 million. The Company's retail share of this amount is 78 percent (the Company's 74.26867 percent share plus the Municipals' 3.73133 percent share), or $19.563 million. The remaining share of these costs is the responsibility of the Pilgrim contract customers. These amounts are reflected in Exhibit BEC-BKR-1, page 4, Column N for 1999.

<u>Exhibit BEC-BKR-4</u>

Q. Please explain Exhibit BEC-BKR-4.

A. Exhibit BEC-BKR-4 contains the final calculation of the Company's 1999 reconciliation adjustment associated with the Pilgrim PBR formula. This amount is reflected in Exhibit BEC-BKR-1, page 4, column P. The Restructuring Settlement, Attachment 3, Section 2.7(b), provides that, if the retail share of the Company's nuclear unit operates at a loss resulting from the provision of Standard Offer Service, the Company may recover such losses through its Transition Charge. If the loss is less than the market-price-to-standard-offer-price differential (representing the forgone revenues the Company sustained as a result of its obligation to provide Standard Offer Service to its customers), then the

Company can recover the loss. When the loss is greater than the market-price-to-standard-offer-price differential, the Company may recover the differential plus 25 percent of the difference between the loss and the differential.

Q. Has the Company complied with provisions of the Restructuring Settlement that requires it to distribute preliminary copies of the Company's reconciliation filing to the Settling Parties and to meet with them to seek a resolution of issues relating to the filing?

A. Yes. The Company distributed preliminary copies of its reconciliation filing to all Restructuring Settlement signatories. In addition, the Company conducted a meeting to which all signatories were invited in order to explain the Company's preliminary filing and to address any issues that were raised. The Company continues to believe that the settlement process is an important mechanism for the resolution of issues, and will continue to pursue appropriate settlements of individual issues such as those addressed in the August 4, 2000 settlement filed in D.T.E. 99-107.

Q. Has the Company sought to address the issues that were left unresolved in the August 4, 2000 settlement filed in D.T.E. 99-107?

A. Yes. Sections 2.6 and 2.7 of the August 4 settlement refer to two issues that the Company, the Attorney General and the Division of Energy Resources did not specifically resolve, but agreed to work together to resolve. The first of those issues concerns the alternative method of reconciling Transition Charge revenues as has been proposed in this filing. Although there has been no formal agreement concerning this methodology, the Company believes that there have been constructive discussions on this issue. The second issue concerns the funding of certain trust funds for the FAS 106 and FAS 87 regulatory assets. The Company has invited an exchange of positions on this issue; however, a formal agreement has not been achieved to date. Consistent with our proposal to make a supplementary filing in the spring of 2001 with updated year-end data, we would hope to provide an update on this issue at that time.

<u>Exhibit BEC-BKR-5</u>

Q. Please describe Exhibit BEC-BKR-5.

A. Exhibit BEC-BKR-5 is consistent with the Company's response to Information Request DTE 4-1 in D.T.E. 99-107, and illustrates the methodology and actual mechanics of how the FERC-approved transmission costs are charged to retail customers (as stated in that response, FERC has exclusive jurisdiction over transmission service). This exhibit derives the proposed average retail transmission rate to be effective January 1, 2001, based on forecast 2000 retail transmission costs per the current FERC-approved tariffs. The 2001 calculation includes the final true-up for 1999 retail transmission costs. The proposed Transmission Charge for the Company, beginning on January 1, 2001, is $0.00538 per kWh.

Q. Generally, what are the transmission costs that constitute the total retail transmission costs?

A. The retail transmission costs are those costs associated with providing Regional and Local Network transmission service to the retail class that utilize an integrated grid of transmission facilities that comprise both POOL Transmission Facilities ("PTF") and NON-PTF. The operation and control of the PTF is governed by ISO New England, Inc. ("ISO") and the costs of the facilities are administrated as such by the ISO under the NEPOOL Transmission Tariff. The Non-PTF costs are administered under the Company's Local Transmission Tariff.

Q. What are the individual component costs that are assessed to the retail class under the NEPOOL Transmission Tariff and under the Local Transmission Tariff?

A. Under, the NEPOOL Transmission Tariff, transmission costs are assessed for Regional Network Service, Scheduling and Dispatch service at the regional level, Congestion Management, and settlement costs that are charged as Phase I and II uplift expenses. Under the Local Transmission Tariff, the transmission costs that are assessed are Local Network Service and Scheduling and Dispatch service at the local level.

Q. Please describe the reasons for the increase in the proposed Transmission Charge compared to the Transmission Charge currently in effect.

A. The increase in the retail transmission rate is attributable to several causes. In 1999, the Company began to incur costs for congestion management and for Phase I and Phase II Uplift Charges that were included as part of a settlement agreement under the NEPOOL Open Access Transmission Tariff. In addition, an increase in the transmission revenue requirement occurred in 1999 as a result of the transition from a stated rate to a formula rate cost of service. The transmission revenue requirement was further increased by FERC's approval to allow the Company to bill transmission customers starting in June 2000 on the basis of a forecasted cost of service.

Q. Does this conclude your testimony?

A. Yes, it does.